BEFORE

THE PUBLIC SERVICE COMMISSION

OF

SOUTH CAROLINA

DOCKET NO. 2019-226-E – ORDER NO. 2020-__

In the Matter of: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated	)))))))	**POST-HEARING BRIEF IN THE FORM OF A PROPOSED ORDER APPROVING DOMINION ENERGY SOUTH CAROLINA, INC.'S INTEGRATED RESOURCE PLAN**

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I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina (the "Commission") pursuant to S.C. Code Ann. § 58-37-40 (Supp. 2019) (the "IRP Statute") and Order No. 98-502 for approval of the 2020 Integrated Resource Plan (the "IRP") of Dominion Energy South Carolina, Inc. ("DESC" or the "Company") as supplemented by additional material filed with the Company's rebuttal testimony (the "IRP Supplement").

DESC filed its IRP on February 28, 2020, which, as required under the IRP Statute, is one year from the filing of its most recent IRP update and three years from the filing of its last full IRP. Timely petitions to intervene in the current docket were received from the Sierra Club; Johnson Development Associates, Inc.; the South Carolina Department of Consumer Affairs; the South Carolina Solar Business Alliance, Inc. ("SCSBA"); and the South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE") (collectively, the "Interveners"). The South Carolina Office of Regulatory Staff ("ORS") was automatically a party to this proceeding pursuant to S.C. Code Ann. § 58-4-10(B).

On June 4, 2020, DESC prefiled the direct testimony of witnesses Eric Bell, James Neely, Therese Griffin, and Joseph Lynch. On July 10, 2020, the ORS prefiled the direct testimony of Anthony Sandonato, Philip Hayet, and Stephen Baron; the Sierra Club prefiled the direct testimony of Derek Stenclik; the SCSBA prefiled the direct testimony of Kenneth Sercy; and CCL and SACE prefiled the direct testimony of Anna Sommer and David Hill. The ORS additionally prefiled the direct testimony of Lane Kollen on July 13, 2020. On August 28, 2020, Company witnesses Bell, Neely, Griffin, and Lynch prefiled rebuttal testimony. On October 2, 2020, ORS witnesses Sandonato, Hayet, Baron and Kollen; Sierra Club witness Stenclik; SCSBA witness Sercy; and CCL and SACE witnesses Sommer and Hill prefiled surrebuttal testimony.

The hearing to consider DESC's 2020 IRP began on October 12, 2020, and ended October 14, 2020. At the hearing, DESC was represented by K. Chad Burgess, Esquire, Matthew W. Gissendanner, Esquire, and Belton T. Zeigler, Esquire. ORS was represented by Jeffrey M. Nelson, Esquire, Nanette Edwards, Esquire, and Andrew Bateman, Esquire. The Sierra Club was represented by Robert Guild, Esquire and Dori Jaffe, Esquire. The SCSBA was represented by Richard Whitt, Esquire and Ben Snowden, Esquire. CCL and SACE were represented by Kate Lee, Esquire, Gudrun Thompson, Esquire, Frank Holloman, Esquire, and Chris DeScherer, Esquire. Johnson Development Associates was represented by Weston Adams, Esquire and Court Walsh, Esquire. The South Carolina Department of Consumer Affairs received notice of the hearing and chose not to appear.

During the hearing, all witnesses who provided prefiled testimony also testified in person. At the request of the Commissioners, several late-filed exhibits were filed after the close of the hearing. At the request of Commissioner Williams, CCL and SACE filed Hearing Exhibit 7 on October 21, 2020, which was an updated chart evaluating whether, in their opinion, the Company met the statutory requirements of S.C. Code Ann. § 58-37-40 in its IRP Supplement. DESC was given the opportunity to respond and did so by Hearing Exhibit 8 filed on October 28, 2020. At the request of Commissioner Ervin, SCSBA filed Hearing Exhibit 13 on October 21, 2020, which was an action plan requiring DESC to implement a procurement of 400 MW of solar capacity in 2021. DESC was given the opportunity to respond and did so by filing Hearing Exhibit 14 on October 28, 2020. In that exhibit, DESC responded substantively to the matters contained in Hearing Exhibit 13 while reserving its argument that ordering DESC to make an otherwise unplanned and unrequested acquisition of solar generation capacity was beyond the statutory powers of the Commission under the IRP Statute and otherwise. At the request of Commissioner

Ervin, on October 21, 2020, the CCL and SACE filed an example of a short-term action plan as Hearing Exhibit 16. DESC was given the opportunity to respond and did so on October 28, 2020, by filing a detailed and complete Short-Term Action Plan (the "STAP") as Hearing Exhibit 17. DESC requested that the STAP it submitted as Hearing Exhibit 17 be included as a part of the 2020 IRP.

II. SUMMARY OF PROCEEDINGS AND FINDINGS

Act No. 62 of 2019 extensively amended the IRP Statute, which now requires that each utility's IRP be reviewed in a contested case hearing with participation by ORS and intervention by interested parties. S.C. Code Ann. § 58-37-40. The amended IRP Statute also provides a detailed list of the required elements and analyses to be included in IRPs and a set of specific standards for the Commission to consider in approving IRPs. *Id.* This IRP proceeding is the first conducted under the amended statute.

ORS's internal experts and the outside consulting firm ORS hired for this proceeding undertook a thorough review of DESC's 2020 IRP. While they found that the required elements of an IRP were present in the IRP, they also identified 19 errors, inconsistencies or matters requiring reevaluation that according to their testimony needed to be addressed or corrected in the current proceeding (the "Current Recommendations"). *See* Tr. at 729.4-729.6. These witnesses (collectively, the "ORS Witnesses") testified that these matters were serious enough to require correction, reevaluation or reconsideration before approval of the 2020 IRP would be justified. *See id.* at 729.4.

In response, the Company acknowledged the value of making the corrections, revisions or reevaluations identified in the Current Recommendations and sought a two-week extension for the filing of its rebuttal testimony to make those changes. *See* Tr. at 65.2. As a part of that rebuttal testimony, the Company submitted a revised version of Section II.B.5 of its IRP (the "IRP Supplement") presenting revised modeling data and results which incorporated, with limited exceptions, all of the specific changes or the results of reevaluations indicated by ORS and some of those indicated by other parties. *See* Ex. 2. According to DESC's testimony, while these changes improved the quality of the IRP analysis, they had limited impact on the comparative standing of the resource plans modeled. Tr. at 56–57. In the revised analysis, no resource plan's cost changed by more than 2.5% in comparison to any other, nor did the revisions change the conclusion of the IRP analysis overall as to the resource plans shown to be most favorable for customers and the utility's generation system. *Id.*

In addition to the Current Recommendations, the ORS Witnesses identified twenty additional improvements, revaluations, expansion or revisions that should be incorporated in future IRPs (the "Future Recommendations"). Tr. at 742.8–742.9. In its rebuttal testimony, the Company responded to each of the twenty Future Recommendations. It agreed, among other things, to initiate a robust stakeholder process in future proceedings; to prepare retirement analyses for its existing coal-fired units and certain other aging fossil generation stations, and to implement more sophisticated modeling software, specifically resource optimization software, the implementation of which was already underway using a well-recognized software package used by another Dominion Energy subsidiary. Tr. at 65.18–65.19. In addition, the Company committed in future IRPs or IRP updates to model an expanded range of load growth forecasts, CO_2 costs, and natural gas prices; to review and reevaluate its reserve margin methodologies and determinations; and to review and reevaluate the methods for forecasting for future natural gas prices, load growth, and demand side management ("DSM") impacts and assumptions. *Id*. The Company reiterated these commitments in the STAP submitted in Hearing Exhibit 17, which it requested to be included in the 2020 IRP as approved by the Commission.

In its surrebuttal testimony, the ORS witnesses acknowledged that the IRP as amended by the IRP Supplement fully satisfied the requirements of the IRP statute and should be approved by the Commission:

> The IRP Supplement adequately addresses and corrects the serious flaws that ORS identified in its review of the IRP and described in the ORS Report that were necessary to modify the IRP in this proceeding and has agreed to improve its IRP planning process in future IRPs, including the implementation of new modeling tools and methodologies used to develop the IRPs.

Tr. at 820.2. Additionally, ORS testified that it was satisfied that,

> the IRP Supplement meets the statutory requirements. The ORS Report designated certain recommendations as necessary for this IRP and other recommendations as necessary for future IRPs. As noted by Mr. Hayet in his Surrebuttal Testimony, the Company has addressed and made nearly all the changes based on the recommendations in the ORS Report necessary for this IRP.

Id. at 820.4.

Having carefully reviewed the record in this matter and the testimony and exhibits it contains, the Commission accepts the determination by ORS that the IRP as amended by the IRP Supplement complies with the terms of the IRP Statute, S.C. Code Ann. § 58-37-40. The Commission further finds that the STAP proposed by the Company includes meaningful measures to improve the IRP process going forward. The Commission orders the Company to include the STAP filed as Hearing Exhibit 17 as filed as part of its 2020 IRP.

III. LEGAL STANDARDS

The amended IRP Statute provides that an integrated resource plan must include the following:

1. A long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
2. The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;
3. Projected energy purchased or produced by the utility from a renewable energy resource;
4. A summary of the electrical transmission investments planned by the utility;
5. Several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following:
    a. customer energy efficiency and demand response programs;
    b. facility retirement assumptions; and
    c. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;
6. Data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;
7. Plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;

8. An analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and
9. A forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

S.C. Code Ann. § 58-37-40(B)(1). Additionally, the integrated resource plan *may* include distribution resource plans or integrated system operation plans. *Id.* at § 58-37-40(B)(2) (emphasis added).

Under S.C. Code Ann. § 58-37-40(C)(2), the Commission is charged with approving an integrated resource plan if it "determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." The statute lists the following factors for the Commission to balance in making this decision:

1. Resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
2. Consumer affordability and least cost;
3. Compliance with applicable state and federal environmental regulations;
4. Power supply reliability;
5. Commodity price risks;
6. Diversity of generation supply; and
7. Other foreseeable conditions that the commission determines to be for the public interest.

Under S.C. Code Ann. § 58-37-40(C)(2), if the integrated resource plan appropriately balances these factors, it shall be approved. *Id.*

IV. <u>DESC'S 2020 INTEGRATED RESOURCE PLAN</u>

A. Overview of Resource Plans and Scenarios Considered in DESC's 2020 IRP

In preparing its 2020 IRP, the Company first identified the range of resources and technologies that were reasonably available to meet customer needs for capacity and energy in future years. Tr. at 36–37. These resources and technologies included solar generation in the form of both utility-owned solar resources and solar energy purchased from third-party developers under power purchase agreements ("PPAs"). Tr. at 283. They also included battery storage resources, combined cycle ("CC") natural gas-fired units, two types of standalone simple-cycle internal combustion turbine ("ICT") units, specifically lower-cost large frame ICT units, and more responsive and fuel-efficient but higher cost aero-derivative ICT units. *Id.* The Company combined suites of these resources with assumptions concerning the possible early retirement of coal-fired units and retirements of other older facilities to create eight resource plans for comparative evaluation. Tr. at 288.6; *see generally* Ex. 1 (presenting the methodology of the 2020 IRP).

Next, the Company identified a set of load forecasts to determine the size and seasonality of peak electrical demands that the Company would be required to meet in the coming years. *Id.* This demand forecast was prepared using load forecasting models historically employed by the Company to project the anticipated growth in energy and capacity demands by rate category or customer class. To forecast future customer demands, these models employ a combination of historical data, load research data, statistical analysis, and projections of future economic growth in the service territory. Tr. at 549.2-549.3. A range of load growth forecasts was considered including three economic growth scenarios with low, base and high growth of 0.25%, 0.7% and

1.7% respectively; two wholesale business scenarios; and three electric vehicle saturation scenarios. In all, there were 18 combinations of different load forecast scenarios represented. Ex. 1 at 12–14. The Company chose the most likely forecast of 0.7% in peak demand as the basis for corporate and IRP planning. *Id.*

The resulting forecast was then adjusted to reflect the impact of DESC's currently-approved DSM programs on load growth. Tr. at 50.6-50.7. The base DSM assumption assumed that the Company was 100% successful in meeting its current Commission-approved DSM targets (which are an approximate 0.7% reduction in sales growth for eligible customers) and is 100% successful in implementing the full amount of demand reduction potential identified in recent DSM filings when advanced metering infrastructure ("AMI") is rolled out to all customers in the next three years. *Id.*

Three levels of DSM were applied to the load forecast creating three load scenarios that were used to test the sensitivity of the eight resources plans to variation in load growth. A high-growth forecast assumed that DESC's recently-expanded DSM programs would not produce any additional sales reductions compared to current levels. A low-growth forecast assumed that DESC service territory would be able to achieve a reduction in future sales growth of 1% among eligible customer groups, an amount that is approximately 43% higher than the current Commission approved target of a 0.7% reduction in sales through the currently-approved DSM program. *See* Ex. 1 at 8.

These load growth forecasts were used to determine the size and timing of resource additions under each of the eight resource plans. Specifically, resource additions were scheduled to meet the winter and summer capacity demands of customers over a 30-year planning horizon. *Id*. at 7. This was done by calculating three sets of winter and summer peak demands for each year over the 30-year planning horizon, each based on either the medium base, high or low DSM assumption. Using these peak forecasts, the eight resource plans were configured to add the appropriate resources when the Company's existing reserves fell below the level necessary to reliably meet customer demands during the summer or winter peak of that year.

The reserve margin requirements used in this part of the analysis took into account the historical availability factors and forced outage rates of DESC existing generation resources, the anticipated availability factors and forced outage rates of new resources, and the effects of extreme weather conditions on customers' energy demands. Tr. at 50.23–50.24.

The production cost of the eight resource plans was then computed by dispatching the generation system reflected in each resource plan on an hourly basis, year by year, over a 30-year planning horizon. Tr. at 50.14. This was done using the PROSYM generation dispatch model, which computes the cost of operating the system on an hourly basis. To test the sensitivities of the resource plans to different forecasting assumptions, operating costs were also computed for each of the eight resource plans under scenarios that varied the assumptions as to medium, high or low DSM; base, high or low natural gas prices; and future CO_2 costs at either $0/ton or $25/ton. Modeling the eight resource plans against the different sensitivity assumptions produced 144 different operating cost calculations for each year of the 30-year planning horizon. Tr. at 292.

These resulting incremental costs for each of the 144 PROSYM runs were then combined with forecasts of the capital costs and other fixed costs associated with the resources added under each of the eight resources plans to compute a 40-year levelized cost for each resource plan.

Out of this modeling, four of the eight resource plans modeled emerged as being of particular importance. The modeling showed Resource Plan ("RP") 2 to have the lowest cost for customers in the reference scenario (base gas costs, medium DSM and CO_2 costs at $0/ton) and in all nine scenarios involving future CO_2 costs at $0/ton. Tr. at 290–291. RP2 was also the plan with the second lowest cost in more than half of the nine scenarios involving $25/ton CO_2 charges. Tr. at 57. RP2 assumes that all existing generation resources remain in operation for the remainder of their useful lives and future customer needs are met principally by adding Frame ICTs as required. *Id.*

RP2, however, is the resource plan that produces the lowest reduction in CO_2 emissions and involves the lowest increase in reliance on renewable resources. For that reason, RP2 was the resource plan that was most vulnerable to future emissions restrictions on CO_2. *See* Tr. at 50.21.

RP8 produced by far the greatest reduction in CO_2 emissions. Tr. at 297.28. It envisions the early retirement of both the Williams and Wateree Stations in 2028 and the conversion of the Cope Station to natural gas-fired only status in 2030. This plan would eliminate all remaining coal-fired generation from DESC's system by 2030. Tr. at 286. Under RP8, the retired generation capacity would be replaced principally by solar and battery storage resources supplemented with several Aero-Derivative ICTs to maintain system reliability. Tr. at 286–87.

RP8 is more expensive than RP2 in all nine scenarios involving future CO_2 costs at $0/ton and is the lowest cost plan in only one of the nine scenarios involving a $25 per ton CO_2 price. However, in scenarios that model a $25 per ton CO_2 price, the difference in levelized costs to customers between RP8 and the higher-carbon emitting alternatives is quite small, while RP8 provides a superior level of CO_2 emissions reduction. Tr. at 65.34.

RP3 is the lowest cost plan in seven of the nine scenarios involving a $25 per ton CO_2 price. Ex. 2 at 10-12. RP3 assumes the early retirement of Wateree Station and reliance on gas-fired resources to replace its capacity. Tr. at 288.9.

RP7 involves no early retirements of coal plants but relies principally on flexible solar and battery storage to meet future needs. Tr. at 288.8. It is the lowest cost plan where natural gas prices are high and a CO_2 prices of $25 per ton is assumed. Tr. at 297.14–297.15. As mentioned above, the cost differences between RP3, RP7 and RP8 are small.

The load and resource data presented in the IRP show that DESC currently has sufficient capacity to meet customer needs for the foreseeable future. No resource procurement decisions are indicated in the near term. Accordingly, in the 2020 IRP the Company presented RP2 as the preferred plan for use in avoided cost calculations and other matters because it is the least cost plan under current conditions. RP8, however, represents the preferred plan should reducing CO_2 emissions be a primary goal in managing DESC's generation portfolio. Tr. at 14–15. RP3 and RP7 could also merit consideration depending on how future load growth and gas price forecasts evolve.

B. DESC's 2020 Integrated Resource Plan Compared to the Statutorily Required Elements for Such a Plan

The Commission finds the testimony of the ORS Witnesses, which is referenced above, to be credible to the effect that the Company's 2020 IRP as supplemented provides the required information as to each of the enumerated elements required by S.C. Code Ann. § 58-37-40(B)(1). The following chart cross references each of the required statutory elements to its location in the 2020 IRP as supplemented:

Act No. 62 § 58-37-40	Requirement	2020 IRP Section Satisfying Requirement	Explanation of How IRP Requirement Was Satisfied
(B)(1)(a)	A long-term forecast of the utility's sales and peak demand under various reasonable scenarios;	I.A I.B	Section I.A provides a long-term forecast for sales and peak demand, under base, high and low load growth scenarios. In addition, Section I.B provides an analysis of the sensitivity of each of the eight resource plans under base, high and low growth case scenarios modeled based on the different assumptions related to the effect of DSM programs on future load growth.
(B)(1)(b)	The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios;	II.B.5.c	Information is provided specifying each type of generation facility proposed, and its proposed capacity. Fuel sensitivities are explicitly presented and discussed in the IRP Supplement in Section II.B.5.c.iv. Base, high and low natural gas price forecasts were modeled as sensitivities for all resource plans.
(B)(1)(c)	Projected energy purchased or produced by the utility from a renewable energy resource;	II.B.3.c	Section II.B.3.c shows the levels of energy provided by renewable energy resources for each resource plan modeled.
(B)(1)(d)	A summary of the electrical transmission investments planned by the utility;	III	Section III delineates each electric transmission project planned by the utility with a projected completion date.
(B)(1)(e)	Several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other	II.B.5.c II.B.3.d	The 2020 IRP and IRP Supplement developed eight resource portfolios that evaluated the range of demand-side, supply-side, storage, and other technologies and services

	technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following: (i) customer energy efficiency and demand response programs; (ii) facility retirement assumptions; and (iii) sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks;		that are available to meet the utility's service obligations. Each was tested for its sensitivity against a range of price, environmental, and DSM-based load variables. The eight plans were studied using • three natural gas price scenarios ("sensitivity analyses related to fuel costs"); • two CO_2 cost scenarios ("sensitivity analyses related to environmental regulations"); and • three DSM cases ("customer energy efficiency and demand response programs"). Cogeneration was evaluated in Section II.B.3.d. Facility retirement assumptions were specified in Section II.B.5.c.
(B)(1)(f)	Data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;	II.B.1 II.B.3 II.B.4.a	DESC's current generation portfolio was set forth in Section II.B.1. Additionally, Section II.B.4.a provides data regarding DESC's 2019 resource mix and a table showing DESC's generation portfolio, including the In-Service Date ("age") and probable retirement date ("remaining estimated life") for each facility in the portfolio.
(B)(1)(g)	Plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;	II.B.5.c	Section II.B.5.c explicitly explains how DESC planned to meet the base resource need.

(B)(1)(h)	An analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and	II.B.5.c	Each of the eight resource plans considered in the IRP is modeled to show levelized cost to customers and reliability based on historical and engineering data concerning the reliability of each of the specific generation resources contained in each resource plan. The reserve margins under each plan were established to ensure the generation system's ability to meet customers' demands reliably and efficiently given the reliability impacts of the resources considered.
(B)(1)(i)	A forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.	I.A II.A.1 II.A.2	2020 IRP contains a forecast of DESC's peak demand. Details regarding peak demand reduction are set forth in Sections II.A.1 and II.A.2. Section II.A.2 sets forth DESC's load management programs. The purpose of these programs is specifically to reduce peak demand.
(B)(2)	An integrated resource plan may include distribution resource plans or integrated system operation plans.	II.A.2 II.B.2	Inclusion of distribution resource plans or integrated system operations plans is optional. However, DESC included information on distribution resource plans in Section II.B.2, titled "Distribution Resource Plans."

The Commission finds that the 2020 IRP considers a wide array of supply and demand-side resources and shows how they can be expected to perform to meet customers' requirements over a range of sensitivities. Each of the eight resource plans evaluated represents a distinct approach for using available supply-side technologies and demand-side resources to meet customers' future demands for energy and capacity. Specifically, each resource plan represents a specific approach to balancing consumer affordability, least cost, environmental compliance, power supply reliability, and commodity price risk diversity in light of potentially foreseeable future conditions on DESC's system. Each of the eight resource plans has been tested against eighteen specific sensitivity cases concerning fuel costs, environmental regulations, and the anticipated variations in load forecasts, modeled as different assumptions as to the impact of DSM efforts on energy sales and demand. Collectively these eight resource plans and 144 resulting scenarios define a broad range of approaches to supplying future customer needs.

The Commission finds that, in addition to meeting the other requirements of S.C. Code Ann. § 58-37-40(B), the eight resource plans modeled by the Company represent "several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations" as the statute requires. S.C. Code Ann. § 58-37-40(B)(1)(e). The IRP sets out "plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan." *Id.* at § 58-37-40(B)(1)(g). It provides "an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs" as they currently exist for adding resources to DESC's system. *See id.* at § 58-37-40(B)(1)(h). It provides "an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures." It specifically models low, medium and high DSM scenarios, including scenarios assuming full achievement of current DSM objectives as the base case and a high DSM case that assumes that the Company exceeds those objectives by approximately 43%. The DSM programs that were considered were those contained in DESC's current DSM programs as approved in Order No. 2019-880. Tr. at 206. Both RP1 and RP2 reasonably represent a cogeneration plan that could utilize the heat produced to create steam for a manufacturing facility since the gas-fired resources installed under them could be configured to provide such a steam supply and any costs of doing so above those modeled in the analysis would be borne by the steam user. Tr. at 288.14.

C. DESC's 2020 Integrated Resource Plan Evaluated Under the Statutorily Required Findings for Approval

Under S.C. Code Ann. § 58-37-40(C)(2), the Commission shall approve an IRP if it finds that it appropriately balances "(a) [the utility's] resource adequacy and capacity to serve anticipated peak electrical load, and its applicable planning reserve margins; (b) consumer affordability and least cost; (c) compliance with applicable state and federal regulations; (d) power supply reliability; (e) commodity price risks; (f) diversity in generation supply; and (g) other foreseeable conditions . . . ."

In its 2020 IRP, DESC has presented eight diverse resource plans, each of which is configured to ensure power supply reliability and resource adequacy, while suppling the capacity needed to meet anticipated peak electrical loads and fostering a reasonable level of generation diversity. Four of those plans, RP2, RP8, RP3 and RP7 are shown to be particularly well-suited to achieving consumer affordability and least cost while minimizing commodity price risks under specific sets of foreseeable conditions concerning potential CO_2 emissions constraints, natural gas price increases, and demand growth.

Specifically, because RP2 presents the least cost plan for customers under current conditions, it is the preferred plan at present. Tr. at 14. RP8 represents the plan that achieves the a markedly greater reduction in CO_2 emissions than the alternatives and so is the preferred plan at present should limiting CO_2 emissions be a predomination consideration. Tr. at 14–15. RP3 and

RP7 can provide advantages to customers under certain load growth and natural gas cost conditions.

Because no resource procurement decisions are indicated in the near term, the Company has determined that the most reasonable and prudent approach to resource planning is to leave its options open and preserve the flexibility to allow it to make a definitive choice between these or possibly other resource plans at a later date. As time progresses, conditions concerning future CO_2 costs, demand growth and usage patterns, changes in natural gas prices, and price reductions in renewable resources due to technology advances will be better known, as will the needs of the customers and the system generally.

The SCSBA witness Mr. Sercy criticized the 2020 IRP as a “do nothing” plan. Tr. at 661. But taking definitive action where definitive action is premature is neither reasonable nor prudent. Therefore, in this IRP, the Company has put forward a preferred plan as one among multiple plans and has made the commitment to continue ongoing monitoring and evaluation of all options pending a future decision point.

In the meantime, the Company has committed to taking steps to further develop its IRP planning process, implement more sophisticated modeling software, conduct retirement studies on older coal fired and other units, review and reevaluate existing forecasting techniques and reserve margin determinations and implement a stakeholder process to provide greater input into its planning process in the future. All of these items are now part of the IRP going forward through their inclusion in the STAP. Accomplishing these tasks will allow the Company to make a better-informed choice among resource plans in the future, when such a choice needs to be made.

For these reasons, the Commission concludes that the 2020 IRP represents the most reasonable and prudent means of meeting the electrical utility’s energy and capacity needs at this time. *See* S.C. Code Ann. § 58-37-40 (C)(2). The Commission concludes that the 2020 IRP satisfies all of the requirements of S.C. Code Ann. § 58-37-40.

V. <u>OTHER ISSUES</u>

As stated above, the Company has responded to both the Current and Future Recommendations raised by ORS, and ORS has indicated through its Witnesses that any outstanding issues, concerns, or differences of opinion related to the methods, data, and inputs used in preparing this IRP were not sufficiently serious to call in to question the conclusions of this IRP. However, not all Interveners agree with this conclusion.

A. The Short-Term Action Plan

SCSBA witness Mr. Sercy testified that a short-term action plan "is an appropriate element to include in an IRP document to clearly identify such actions that are expected to be taken, whether or not those actions require additional regulatory proceedings in order to be fully carried out." Tr. at 615.10. ORS also recommended that the Company should be required to include a three-year Action Plan in future IRP reports. *See id.* at 748.24. Examples of action plans cited as potential models included those of Duke Energy Carolinas and Duke Energy Progress, and Dominion Energy Virginia and Dominion Energy North Carolina. *See* Ex. 6 at AS-3; Tr. at 748.25–748.26.

In response, in Hearing Exhibit 17, DESC submitted a STAP for adoption as part of its 2020 IRP. The Commission finds that the STAP contained in Hearing Exhibit 17 (a) is consistent in scope and content with those included in the IRPs of other South Carolina and regional utilities, (b) provides the appropriate balance of commitment and flexibility to allow the IRP process to function effectively going forward, and (c) captures the commitments made by the Company in its testimony and other filings in this proceeding. The Commission further agrees, as DESC witness

Bell has testified, that approval of an action plan or otherwise cannot legally authorize or require the Company to undertake any resource procurement steps. Tr. at 65.29. However, the STAP constitutes a set of representations to the Commission and the public concerning the Company's intended actions, which the Commission intends to hold the utility accountable for in future IRP proceedings.

B. Stakeholder Process

CCL and SACE witness Sommer testified that, "[a] common practice is to conduct a stakeholder process prior to the filing of the IRP." Tr. at 476.28. "These stakeholder processes are often intended to help the parties understand each other's viewpoints, provide feedback on the assumptions made by the utility, and ideally narrow the number of contested issues in the IRP case." *Id.* Other interveners and ORS agreed.

DESC witness Bell testified in response that the Company would implement a stakeholder process as soon as possible with the caveat that the Company must be able to "retain appropriate control over the plans that are presented as part of its IRP planning process," as it has a direct obligation to customers to provide "safe, reliable and affordable electric service…." Tr. at 65.27–65.28.

A stakeholder process is not listed as a necessary element of an IRP under S.C. Code Ann. § 58-37-40(B), and the failure to conduct one is not a violation of the statute. DESC witness Bell testified that it is too late at this time to implement a full stakeholder process prior to the filing of the next IRP update, which is due in February of 2021, but that a robust IRP stakeholder process could begin in summer 2021 in support of the 2022 IRP update. Tr. at 65.28. ORS agreed that it is "reasonable to wait for the 2022 IRP to begin this process given that the Company will not have much time between when an order is issued in this proceeding and when the next IRP will be filed in February 2021." *Id.* at 748.23. Additionally, ORS testified that waiting to begin the process until the summer of 2021 would give all parties the opportunity to plan and propose parameters for the stakeholder process. *Id.* at 748.23-748.24.

The Commission agrees that it is reasonable to initiate a stakeholder process for the 2022 IRP update. The Commission believes that, for the long-term success of the stakeholder process, it is best to give the parties time to collaborate to develop a process that works in this particular context without the Commission specifying the structure of that process in detail at the outset. The Commission expects the Company to use the flexibility it is being granted here to work collaboratively with stakeholders to implement a robust process that, as Ms. Sommer testified, will accomplish the goal of allowing the parties to understand each other's viewpoints, provide feedback on the assumptions made by the utility, and ideally narrow the number of contested issues in the IRP case.

C. Retirement Studies

Both ORS and certain interveners argued that DESC should be required to perform detailed retirement studies on its remaining coal units. The ORS Witnesses testified that the Company should conduct a detailed retirement study that addresses "all potential early retirement candidates including the Williams, Wateree, Urquhart, and McMeekin coal, gas-fired steam turbine and gas-fired combustion turbine ("CT") units." Ex. 20, AMS-1 at 8. However, ORS did not recommend that these studies should be completed earlier than the 2023 IRP.

The Sierra Club's witness Stenclik argued that retirement studies should start "as soon as possible" and be completed prior to the next full IRP cycle in 2023. His concern was that the studies be completed before any definitive decision was made to proceed with Effluent Limitation Guidelines ("ELG") upgrades at Williams and Wateree stations. *See* Tr. at 711.22–711.23.

SCSBA witness Sercy testified that "DESC should be required to perform a comprehensive coal retirement analysis to inform development of its 2021 IRP [update]…." *Id.* at 615.31–615.32.

In its testimony, the Company explained that retirement studies are "time consuming, resource intensive and expensive." Tr. at 65.21. Because the retirement study for each major unit depends on the retirement dates for those selected for other units, the studies "cannot all be done at once and will need to be sequenced and prioritized." *Id.* In the STAP, the Company stated that it intends to initiate studies for the initial retirement candidates, including Wateree Station, no later than early 2021, and Urquhart 3 and McMeekin beginning later that same year, with the intention to have them completed in time to be reflected in the 2022 IRP update, if possible. An additional study for the retirement of Williams Station would follow once the implications of the other studies are known. All retirement studies will be completed before any definitive decision is made concerning ELG upgrades.

The Commission agrees with the approach and timing for retirement studies stated in the STAP. The Commission expects the Company to initiate the initial round of retirement studies in early 2021 with the intention of completing them in 2022.

D. Demand Side Management ("DSM") Scenarios

As discussed above, the 2020 IRP modeled three DSM scenarios. The low DSM case assumed that DESC was unable to increase DSM savings even after expanding its suite of DSM programs approved in Order No. 2019-880 and doubling its DSM investment. Tr. at 50.7. This results in an assumed 0.33% reduction in annual energy sales. *Id*. As DESC witness Griffin testified, this is a sensitivity assumption. Tr. at 247. The Company is working hard to ensure that this assumption never becomes a reality.

The medium DSM case incorporates the targets that were established under the expanded program portfolio approved by Order No. 2019-880. It assumes that DESC will be 100% effective in achieving those DSM targets. Tr. at 272. In short, the medium case assumed a high level of DSM effectiveness given the suite of programs approved by the Commission.

At the hearing, Ms. Griffin explained that DESC created its current DSM portfolio using a "ground up" approach, meaning it built its programs to reflect the full range of potential programs that are practical to implement and cost-effective, not with the goal of meeting a specific target. Tr. at 221. As Ms. Griffin testified,

> In [the DSM proceeding], Mr. David Pickles, the ICF witness who sponsored the 2019 Potential Study, explained that the study did not model specific 'cases' but evaluated specific energy saving measures to determine which ones would be cost effective if implemented in DESC's service territory. The evaluation was conducted using the Total Resource Cost ('TRC') Test, which is the industry standard for evaluating cost effectiveness. The analysis included energy savings that had been evaluated during the first eight years of the programs and added natural gas and water savings where such savings could be anticipated…All measures that passed the TRC test were included in the programs that were presented for approval by the Commission and in fact include some specific measures that did not pass the TRC but would be difficult to unbundle from related measures that did pass.

Tr. at 225.5–225.6. This approach resulted in building up to a suite of DSM programs that were calculated to result in a 0.7% reduction in sales growth for applicable customer.

The DSM high case projected a 1.0% annual reduction in energy sales from eligible customers due to DSM programs or other efficiency gains. Tr. at 225.2. The 2020 IRP explained that "the High DSM case was not supported in the 2019 Potential Study and is based only on estimates, likely not achievable and cost effectiveness is unknown." Tr. at 228. As DESC witness Griffin testified:

> The 2019 Potential Study represented a thorough evaluation of existing and expanded programs and measures to quantify a reasonably achievable reduction in energy sales and demands on DESC's system. That study did not support a level of DSM energy sales reductions as high as 1%. Therefore, the High DSM case was put forward as a planning assumption only and did not indicate that a DSM plan could be formulated to deliver that level of savings consistent with the cost effectiveness requirement of South Carolina law.

Tr. at 225.2–225.3. Certain Interveners argued that the 2020 IRP should be rejected because it did not appropriately or fairly evaluate a high DSM case as statutorily required. However, this argument does not align with the record in this proceeding. DESC in fact evaluated a high DSM case, one that assumed that the Company achieved sales growth reductions that are approximately 43% higher than those that were determined to be achievable in Order No. 2019-880, which was issued after a fully contested hearing approximately ten months ago.

In her testimony, DESC witness Griffin pointed out that this assumed 43% increase in DSM effectiveness was unsupported by the 2019 DSM Potential Study. Tr. at 225.3. This statement is factually accurate. The 2019 DSM Potential Study identified those programs and measures that could be implemented in a practical and cost-effective way at this time. It calculated that those programs could achieve a 0.7% reduction in energy sales. It did not find that a 1.0% reduction in sales growth was achievable.

The Interveners point out that in many of the scenarios modeled, those scenarios based on high DSM assumptions produced lower levelized costs compared to the medium DSM scenarios. Tr. at 681.26. This is not unusual. As a matter of course, and all other things being equal, lower demand growth results in lower incremental costs of providing energy and capacity to customers.

But the record also shows that the IRP modeled all eight resource plans against the high DSM case, and the comparative results under high DSM scenarios were not materially different from those under the low and medium DSM scenarios. Under all three DSM assumptions, RP2 was the lowest cost resource plan where a CO_2 cost of $0/ton was assumed. Under all three assumptions, RP3 was the lowest cost resource plan in a majority of scenarios involving CO_2 costs of $25/per ton. In short, the high DSM assumption of a 1.0% sales reduction was fully modeled and the results taken into account in the IRP analysis. Tr. at 225.2–225.3.

ORS recommended "that in future IRPs, the Company should only use assumptions that it has confidence in and believes are reasonable and achievable." Tr. at 742.10–742.11. In response, the Company committed that in future IRPs, even when defining the outer limits of sensitivity analyses, it will utilize DSM assumptions that it believes are reasonable and achievable. Tr. at 748.16 (citing ORS AIR 1-18 part d response). ORS was satisfied with this response. Tr. at 748.16.

However, in Mr. Hill's rebuttal testimony and in late-filed Hearing Exhibit 16, CCL and SACE requested that the Company be required to review aspects of its current DSM plans to determine if a 1.0% energy savings target can be achieved. The Company responded that such a mandate is outside of the scope of an IRP proceeding, and would be directly contrary to the Commission's determination in Order No. 2019-880 that the recently-adopted DSM programs should be implemented and their effectiveness evaluated without regulatory mandated changes for a period of five years. Tr. at 50.10. In addition, Company witness Griffin provided evidence demonstrating that achieving a 1.0% energy savings target would be highly uncertain given current conditions in the energy efficiency marketplace and other factors. Furthermore, few utilities are able to achieve it. Tr. at 221–223. In fact, in the 2019 DSM proceeding CCL and SACE proposed setting a DSM target at the 1.0% level, and that proposal was rejected by the Commission in Order No. 2019-880 as unjustified. Tr. at 225.9–225.10; Order No. 2019-880 at 15-17.

Nonetheless, in the STAP filed in partial response to Mr. Hill's request, the Company agreed on a voluntary basis to undertake a targeted review of its DSM programs to determine whether a 1.0% level of savings can be achieved within the cost-effectiveness limits imposed by the statute. DESC has agreed to have its outside DSM consultant, ICF, assess the potential of expanding the six DSM programs identified by Mr. Hill in Hearing Exhibit 16 to achieve a 1.0% target. The Company intends to have the assessment available for presentation to stakeholders prior to the review and possible approval for implementation by the Commission during the annual DSM update proceeding in January of 2021. The Commission finds that this commitment is a sufficient response to the request by CCL and SACE related to DSM matters.

E. Inputs Used in the 2020 IRP Modeling

As discussed above, certain inputs used in DESC's modeling were revised based on the direct testimony of the ORS Witnesses and certain overlapping or analogous revisions suggested by Interveners. While ORS was satisfied with the response as a whole, certain interveners continued to object that their suggestions were not adopted. *See, e.g.*, Tr. at 607.16-607.17, 607.29-607.30; 615.11, 615.17, 615.23-615.24; 711.4, 711.7-711.8; 681.7.

The Commission has considered the evidence presented for each of the alleged errors or other objections and does not find that that they provide a basis for rejecting the 2020 IRP. In its testimony and exhibits, the Company has explained the methodology and reasoning for each of the matters in dispute, and that explanation is credible. The Interveners have not shown that the Company's inputs, methodologies or assumptions are definitively incorrect. In several cases, it appears that the Interveners have taken their preferences, preferred methodologies, or preferred data sources and asserted that adopting them is mandatory even though there is no support for that position in S.C. Code Ann. § 58-37-40(B) or otherwise. Taken as a whole, these asserted errors do not provide a basis for rejecting the 2020 IRP.

However, one matter worth addressing is SCSBA's contention that DESC's solar capacity assumptions are at odds with the avoided cost determinations made in Order No. 2020-244. In that order, the Commission adopted an 11.8% Effective Load Carrying Capability ("ELCC") value for measuring the year-round contribution by solar resources to system reliability. This percentage was used for calculating the avoided capacity cost rates for QF solar resources under PURPA.

But as the Company's witness Dr. Lynch testified, the ELCC is not a measure of a resource's contribution to meeting peak-day demand. Instead, it measures year-round contribution to reliability, on peak days and non-peak days. Tr. at 559.24. Specifically, in computing an ELCC, a contribution to reliability is calculated for each day of the year and that contribution is computer cumulative. On some days, the contribution can be zero. That is the case for solar generation on winter peaks, which occur before or near sunrise, when solar cannot make a reliable contribution to meeting peak demand. For solar resources, the peak capacity contribution and the ELCC for the winter peak hours is effectively zero. *Id.*

Therefore, the fact that solar provides an 11.8% ELCC value year-round provides no information about what capacity solar resources provide to meet winter peak. As Dr. Lynch testified "[i]t would be irresponsible for the Company to assume that solar PV could make an 11.8% contribution to winter peak when as a matter of engineering it would not be able to do so." *Id.*. Solar cannot provide capacity before sunrise. Thus, the modeling correctly reflects the contribution of solar resources to winter peak capacity.

F. Mr. Stenclik's Alternative Analysis

The Sierra Club's witness, Mr. Derek Stenclik, proposed that DESC should retire both the Williams and Wateree coal stations in 2026 and replace their 1,294 MW of coal capacity with 460 MW of solar and storage capacity. Tr. at 705.31-705.32. This proposal was made based on a set of analyses Mr. Stenclik performed to show that this approach would result in lower costs to customers.

The Commission finds that the decision concerning whether the retirement of these coal units is advisable in 2026 is not a decision that should be made in advance of the completion of the retirement studies that will be undertaken in 2021 and 2022. Those studies will identify transmission constraints and yet-to-be-quantified environmental and site restoration costs that must be taken into account before determining that such a step is in customers' best interests. Any decision on these matters at this time would be premature.

In addition, Mr. Stenclik's analysis is itself flawed. As DESC witness Neely testified, Mr. Stenclik used a combined price for large frame ITC Turbines and higher cost aero-derivative turbines that inflated the price of large frame ITC turbines to $899/kW. Mr. Neely testified: "A utility pays a substantial cost premium for the fast-start capability and favorable heat rate of ICT-Aero units. To treat them as having the same cost as ICT-Large Frame units would be a mistake." Tr. at 297.10. Mr. Stenclik also eliminated aero-derivative ITC turbines from RP8, which are necessary to maintain reliability. Mr. Stenclik then created load forecasts for DESC using five years of recent data only. His peak demand forecasts are approximately 10% lower than those used by Company, which results in artificially lower costs and inadequate reliability. *Cf.* Ex. 1, IRP at 54 *with* Tr. at 705.33, Table 4. The misleading use of lower loads bypasses the most fundamental point of comparison between resource plans and their costs. Any plan would have more attractive fuel and construction costs given lower loads, but not by the merits of the plan. These plans also have inadequate reserve margins when compared with the most likely forecasted system load peaks and do not provide a reliable solution. It also does not appear that Mr. Stenclik's computations take into account the applicable revisions contained in the Current Recommendations of ORS.

And as DESC witness Neely testified:

> Mr. Stenclik's alternative resource plan models are simply unworkable. They assume that DESC can retire 1,294 MW of coal capacity and replace it with only 460 MW or 920 MW of battery storage and associated solar capacity. Mr. Stenclik says (p. 32) that he assumes that the capacity shortfall can be met through "existing gas resources, and limited imports." But there are no existing gas resources that are not already accounted for on the system. Imports of power from neighboring utilities cannot be relied upon to provide capacity during winter peak when neighboring utilities can be expected to be equally stressed. In addition, Mr. Stenclik treats short-term demand response capacity as a capacity that can be used year round to meet base capacity shortfalls, which is itself unreasonable. Demand response is a time-limited resource. Most critically, Mr. Stenclik's model provides no capacity reserved to meet extreme winter peaks, which as Dr. Lynch testifies, will occur over time. The result of implementing Mr. Stenclik's resource plans would be an unreliable electric system, particularly during times of extreme cold and peak winter demand.

Tr. at 297.31. Based on his study, Mr. Stenclik recommended on behalf of the Sierra Club that the Commission open a new docket "specifically related to the retirement of Williams and Wateree coal plants." *Id.* at 705.37. There is no basis to do so at this time. Consideration of the retirement of those plants should wait until the retirement studies being undertaken by the Company are completed.

G. Conclusion as to Interveners' Proposals and Criticisms

Rejecting the 2020 IRP based on the issues raised by Interveners would be particularly unwarranted considering that DESC has committed to reevaluate or reconsider almost all relevant aspects of its IRP process for future IRPs and to do so as part of a robust stakeholder process. Specifically, the Company has committed in its STAP and rebuttal testimony to:

1. Conduct retirement studies.
2. Implement a stakeholder process.
3. Implement a resource optimization model.
4. Conduct specific DSM studies with the goal of expanding identified programs to achieve a 1% reduction in sales to applicable customers.
5. Provide a more thorough presentation of its load and energy forecasting methodology in the IRP documents themselves.
6. Review its residential and commercial peak load forecast methodology and evaluate the degree to which additional behavioral factors should be included in these forecasts.
7. Expand the number of sensitivities the IRP analyzes to include both DSM scenarios and a range of load growth sensitivity factors as appropriate.
8. Provide a more detailed analysis of its reserve margin methodology and its treatment of VACAR load sharing requirements in future IRP documents.
9. Evaluate whether to continue to use two reserve margins for each season.
10. Revisit its DSM assumptions and limit high DSM assumptions to reasonable and achievable levels.
11. Reexamine its natural gas forecasts and their relationship to other industry forecasts while expanding the range of forecast sensitivities to provide more variation in range from the base or expected price curve.

12. Provide a discussion in future IRPs of the availability and constraints of natural gas pipeline capacity and supply on the timing, size, and location of potential new CC and ICT resource additions for so long as those issues are relevant to the current IRP.
13. Include additional CO_2 price sensitivities in future IRP scenarios based on appropriate forecasts.
14. Reevaluate its assumption regarding its reliance on generic winter capacity purchases and ensure that any decision to consider those capacity purchases is made based on the availability and economics of the capacity purchases.

Tr. at 65.18-65.19; Ex. 17.

The Commission accepts the Company's commitment to address this broad range of issues. Accordingly, the Commission does not believe any additional mandates on the Company for future IRPs or IRP updates, other than those previously discussed, or changes to this IRP prior to its approval are necessary at this time.

H. Implementation of a Least Cost Optimization Model

While all parties support DESC implementing a resource optimization model, SACE's and CCL's witness Ms. Sommer proposed that the Commission should order DESC to,

1. Engage in a collaborative process to choose a capacity expansion model for future IRPs;
2. Negotiate a discounted, project-based fee that permits interested interveners the ability to perform their own modeling runs in the same software package as DESC during the pendency of its IRP cases; and
3. Consider whether to direct DESC to absorb the cost of these licensing fees.

Tr. at 479.5. SCSBA also made recommendations concerning a collaborative process surrounding the implementation of the new software. *See also id.* at 615.30.

Witnesses for DESC testified that a well-recognized software package in general use in the industry, PLEXOS, is being implemented by DESC under a license agreement with Dominion Energy, Inc. Tr. at 65.25-65.26. PLEXOS is the model that is used elsewhere in Dominion Energy, Inc.'s footprint, which allows DESC to access support and know-how from its sister utility. *Id.* at 65.26. Dominion Energy owns additional licenses covering DESC, and implementation of the PLEXOS software is already underway. *Id.* In these circumstances, the Commission does not believe that it is appropriate to order DESC to stop implementing this software model pending a consultative process with other parties to review its software selection.

Regarding permit and licensing fees, the Commission believes that the question of whether it is possible to negotiate a project-based fee should be taken up in the stakeholder process. While DESC pays the cost of consultants employed by ORS as required by statute, there is no statutory authority authorizing the Commission to order utilities to pay for software licenses for advocacy groups or members of the public who wish to participate in IRP proceeding.

I. The Forced Procurement of 400 MW of Solar Only Resources

During the hearing, the SCSBA, through its witness Mr. Sercy, proposed that the Company should be forced to procure 400 MW of solar and storage capacity ("solar resources") outside of the IRP process on an accelerated schedule. At the request of Commissioner Williams, the SCSBA filed as Hearing Exhibit 13 a "Competitive Procurement Action Plan" (the "CPAP") as a late-filed exhibit. In the CPAP, the SCSBA sets forth an aggressive timeline of actions for completion of a 400 MW solar resources-only procurement and contracting for those resources by third quarter

2021. SCSBA claims this deadline must be met "so that participating bidders can take advantage of the 22% Investment Tax Credit." Ex. 13.

However, as the record amply demonstrates, DESC does not have any need for additional capacity or energy on its system its system, especially not in the "near term" as the proposal states. The Company has recently added approximately 973 MW of solar capacity to its system and the 540 MW Columbia Energy Combined Cycle Unit that it recently purchased at a deeply discounted price from a non-utility developer. Tr. at 13. There is no basis in DESC's load and resource data for adding additional capacity.

Additionally, as DESC points out, there is no cost benefit to customers from the forced procurement of additional solar resources at this time. *See* Ex. 14. As established in the Commission's recent avoided cost proceedings, the cost of producing the next increment of power on DESC's system, *i.e.*, its avoided cost, is significantly below the cost of adding solar resources. That fact has been established after extensive litigation that resulted in an avoided cost of approximately $30 per MWh. *See* Docket No. 2019-184-E. Even with the full increment of tax credits that are available today, adding 400 MW of new solar resources will not save customers money.

In sum, the evidence of record shows that under current circumstances, the procurement of 400 MW of solar capacity cannot be justified in its own right, but can only be justified if solar resources are priced independently of any consideration of need, and insulated from competition with other means of meeting customers' requirements. To this end, the SCSBA proposes that the Commission order DESC to procure 400 MW of solar capacity so long as the bids it receives are priced below an artificial ceiling computed without reference to alternative supply resources, or indeed, the need for the 400 MW of capacity at all.

Specifically, the SCSBA proposes that DESC be ordered to compute a ceiling price by modeling the cost of adding 400 MW of solar resources to its system in the "near term," whether that capacity is needed or not (and it is not). *See* Ex. 13. Other resources would not be allowed to be considered as alternatives to solar resources in that modeling. The Commission would then require DESC to accept bids for those 400 MW so long as the bids were below the cost of solar resources as modeled without reference to other resources. Thus, solar resources would compete only against the modeling of other hypothetical solar resources, and DESC would be required to purchase them whether they are needed or not, and whether they save customers money or not. For this reason, the SCSBA's proposal is fundamentally flawed.

By contrast, in a pro-customer procurement plan, no procurement would be triggered unless the need for the capacity and energy were validated independently of developers' interests in making a sale. Then the Company should be required to seek bids from all types of generation resources, and bid its own resources into the mix, to ensure that customers are in fact getting the best deal. The proposal made by SCSBA, however, expressly states that "any procurement should be open to both solar-only and solar-plus-storage resources." Ex. 13.

The Commission finds that the actual needs of DESC's system and the interest of its customers must dictate size and timing of the procurement of additional capacity. Furthermore, the Merger Settlement Agreement with SCSBA specifies that new resources greater than 75 MW will be procured through ***all source*** RFPs. Implementing a requirement for a solar-only procurement on the Company would be contrary to that Agreement. In addition, by locking 400 MW of capacity in place at this time, the option will be lost for procuring that capacity in the future when it can be timed and sized to specific needs and when customers can benefit from the declining cost of solar and battery technology.

For these reasons, accepting the SCSBA's proposal is contrary to the interest of customers and contrary to sound resource planning. Furthermore, the proposal is outside of the scope of this IRP proceeding. Indeed, the SCSBA in its comments in Hearing Exhibit 13 agrees: "[E]stablishment of a competitive solicitation framework (and any required modeling) should proceed independent of any revised IRP."

The sole statutory authority granted by the General Assembly to this Commission related to energy procurements is the authority "to open a generic docket for the purposes of creating programs for the competitive procurement of energy and capacity from renewable energy facilities by an electrical utility within the utility's balancing authority area if the commission determines such action to be in the public interest." S.C. Code Ann. § 58-41-20(E)(2). This provision does not allow the type of action proposed here which is to open a specific docket to require the specific procurement of a specific block of power. For all of these reasons, the Commission rejects the SCSBA's proposal as outlined in Hearing Exhibit 13.

VI. ORDER

IT IS THEREFORE ORDERED THAT:

1. DESC's 2020 IRP, including the IRP Supplement, as filed in this proceeding is approved.

2. Exhibit 17 is accepted as the Company's short-term action plan and is included in this IRP.

3. A stakeholder process should be implemented in which all interested parties can participate in preparation of the 2022 IRP update and the 2023 IRP.

4. The Company shall continue to file its updates to this IRP in February of 2021 and 2022 and shall file its next IRP no later than February 2023, all as required by statute.

This Order shall remain in full force and effect until further Order of the Commission.

IT IS HEREBY ORDERED**.**

BY ORDER OF THE COMMISSION:

____
Justin T. Williams, Chairman

ATTEST:

____
___________________, Vice Chairman
(SEAL)